Asset Management Plan 2020

Update 1 April 2020 - 31 March 2030

COUNTIES POWER

$60m
Network Investment

DISCLAIMER The information in this document is provided in good faith and represents Counties Power’s opinion as at the date of publication. Counties Power does not make any representations, warranties or undertakings either express or implied, about the accuracy or the completeness of the information provided; and the act of making the information available does not constitute any representation, warranty or undertaking, either express or implied. This document does not, and is not intended to; create any legal obligation or duty on Counties Power. To the extent permitted by law, no liability (whether in negligence or other tort, by contract, under statute or in equity) is accepted by Counties Power by reason of, or in conjunction with, any statement made in this document or by any actual or purported reliance on it by any party. Counties Power reserves all rights to alter, in its absolute discretion, any of the information provided in this document. This AMP update was prepared prior to the March 2020 COVID-19 response and does not take into consideration any impact from level four response timeframes, economic impact or resource constraints. The effects of these will be addressed in the 2021 AMP.

Location:
14 Glasgow Road,
Pukekohe, Auckland, 2120,
New Zealand

Postal Address:
Private Bag 4,
Pukekohe 2340,
New Zealand

Phone: 0800 100 202
Fax: 09 238 5120
Email: service@countiespower.com
Web: www.countiespower.com

100%
CONSUMER OWNED

Table of Contents

1. Executive summary

This 2020 Asset Management Plan Update (AMP Update) provides an update to our investment plans and asset management practices that have occurred since we published our 2019 AMP.

Specifically, for this update, in accordance with the Information Disclosure Determination, we have incorporated the following updates:

- An update on our service levels;
- The material changes to network development;
- The material changes to the lifecycle asset management (maintenance and renewal);
- The reasons for the material changes to our 2019 disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b; and
- Updated regulatory Schedules:
    - Forecast Capital Expenditure in Schedule 11a;
    - Forecast Operational Expenditure in Schedule 11b;
    - Asset Condition in Schedule 12a;
    - Forecast Capacity in Schedule 12b;
    - Forecast Network Demand in Schedule 12c; and
    - Forecast Interruptions and Duration in Schedule 12d.

Demand on our network continues to grow in the Pukekohe, Drury, Karaka, Glenbrook and Pokeno areas. This has, and continues to drive our investment in zone substations, capacity upgrades and reliability improvements. As such, our key focus remains on cost-effectively increasing the reliability of our network whilst meeting the demand for new connections resulting from both housing and industrial/commercial developments.

As better information has become available regarding residential and industrial developments in our region, we have reviewed the forward program and re-scheduled projects to reflect the latest growth forecasts, which has resulted in a revision to the forward capital expenditure. Thus changes identified to the capital works program within this AMP Update largely relate to the timing of projects and programmes.

This update indicates that our capital investment across the planning period will reduce by $6m on the 2019 AMP planning period. This is largely due to the deferral of a few major system growth projects in the latter years (FY29 onwards) of the planning period.

The establishment of the new 110/22kV substation at Pokeno required to meet the substantial industrial developments that have taken place is scheduled to be completed in early FY21, however the previously expected significant industrial growth south of Drury has not yet occurred. The result of this is that the planned substation in the Drury South area has been deferred. However, the major project to build a new substation near Bombay has been brought forward, which will allow us to de-commission two end of life 33/11kV substations (Ramarama and Mangatawhiri) and for the existing end of life Transpower 33kV assets at Bombay GXP to be retired as well. This work is expected to enable the deferment of the proposed Drury South area substation for some years, dependant on the uptake and usage of the newly created industrial zoned areas.

We have reviewed the results of recent performance improvement projects on our network with favourable results observed in 2019 year on year. However, our performance remains unfavourable to target and we are introducing further initiatives to improve customer service and reduce unplanned outages. These initiatives include network automation, reducing ICP numbers per feeder, targeted approaches to vegetation issues - particularly those resulting from flying debris from out of zone trees[1], and seeking to reduce third party interference (e.g. vehicles vs. poles).

Forecast OPEX across the planning period is $201m which is an increase of $28m from the 2019 AMP forecast. This is reflective of the growing asset base on the network.

Overall, we believe that the changes identified in this AMP Update will ensure we meet the growth in demand from developments and improve the quality of service that the network provides our consumers with minimal impact on costs and prices.

Period covered by the 2020 AMP Update

This AMP Update covers the period from 1 April 2020 to 31 March 2030 (planning period).

Approval date

This AMP Update was reviewed and approved by the Counties Power Limited Board of Directors on 1 April 2020.

Purpose of this document

The purpose of the AMP Update is to inform and communicate to our stakeholders the material changes in asset management from our 2019 AMP. These changes are provided to reflect our latest demand forecast which is aligned with the high levels of growth in the area and to accelerate ageing asset renewal and replacement to meet our stakeholder requirements in accordance with our asset management strategy and objectives.

This AMP Update is not intended to be a fully self-contained plan, but rather is an update to and should be read in conjunction with our 2019 AMP. Our 2019 AMP can be found at https://www.countiespower.com/vdb/document/130.

Intended audience

The intended audience for this AMP Update is our stakeholders. This includes our customers, our community, our shareholders, the Commerce Commission and the Electricity Authority, our staff and contractors, and other interested parties.

[1] Vegetation management as related to distribution networks are governed by the Electricity (Hazards from Trees) Regulations 2003. Out of zone trees are those that are not covered by these regulations.


SERVICING OVER
43,000
HOMES, FARMS & BUSINESSES

2. Service levels

2.1. Customer service performance

A recent customer satisfaction survey, undertaken by an external research company was completed in November 2019. The results reinforced Counties Power's key focus areas for customer satisfaction, with value for money, reliability and communication remaining as areas of importance for our community.

In FY17, communication was identified as a key influencer of satisfaction. In response, we invested in a customer relationship management system, implemented in FY19. This system provides a platform for delivering improved and tailored customer communication via the channel of the customer's choice.

Additional surveys are undertaken on a monthly basis, providing a pulse on customer satisfaction. This provides assurance that delivery methods are meeting customer expectations and identifying areas for improvement where satisfaction results dip.

2.2. Workplace safety

We have grouped our safety performance targets into two categories. These are:

- **Leading indicators.** We continue to monitor, promote and encourage safety observations and safety audits. We also undertake independent external safety audits to identify areas for continuous improvement.

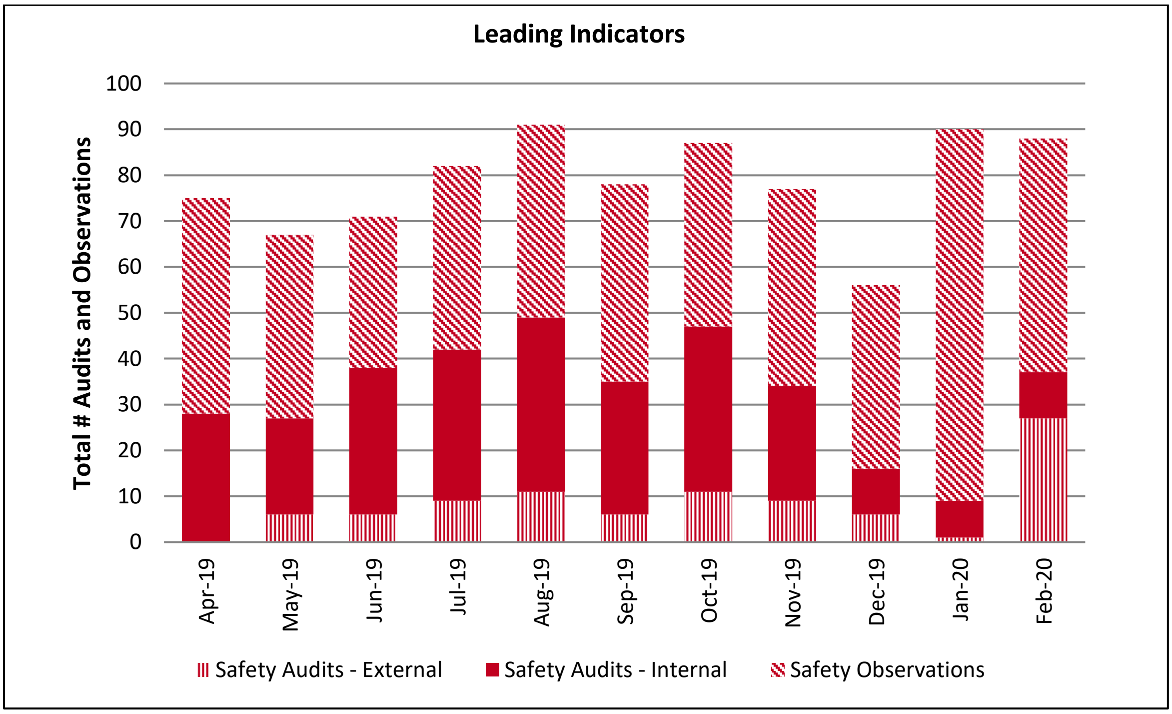

Figure 1 Workplace safety leading indicators

- **Lagging Injury Rate Measures.** Under this category we measure total recordable injury frequency rate (TRIFR) which encompasses all lost time, restricted work and medically treated injuries using a calculation based on 1 million hours. We also measure lost time injury frequency (LTIFR) which encompasses the total number of lost time injuries and total lost days. Our company wide target for each measure is to reduce to zero.

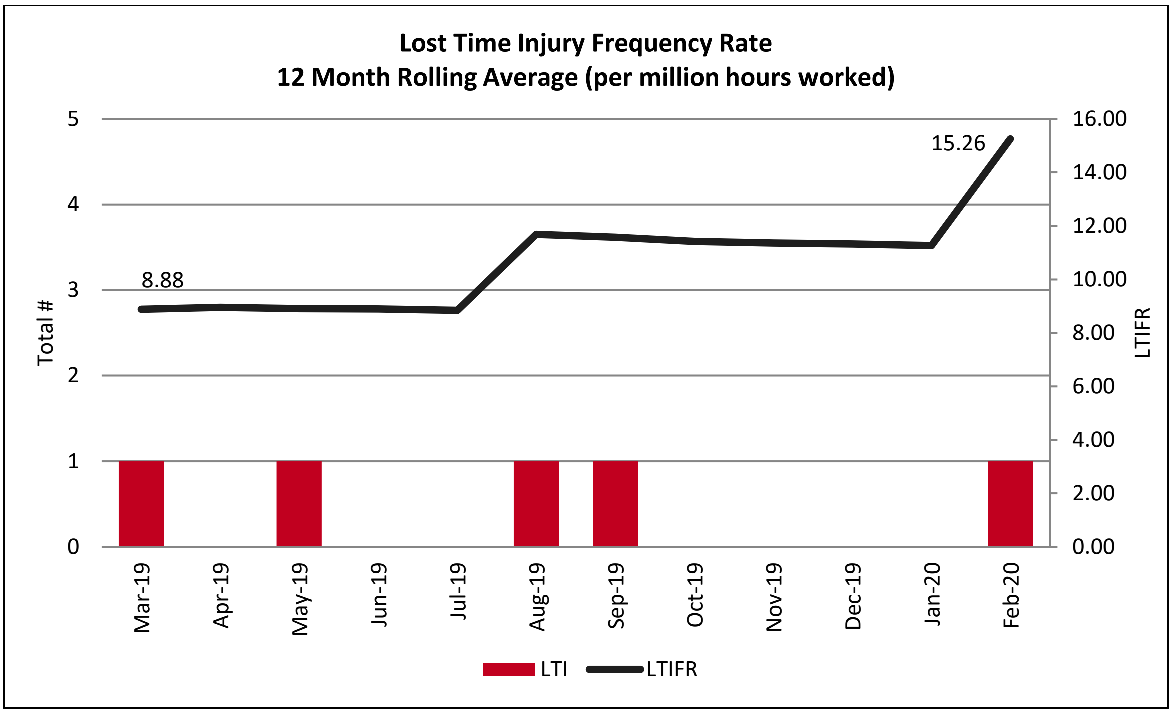

Figure 2 Lost Time Injury Frequency Rate (LTIFR)

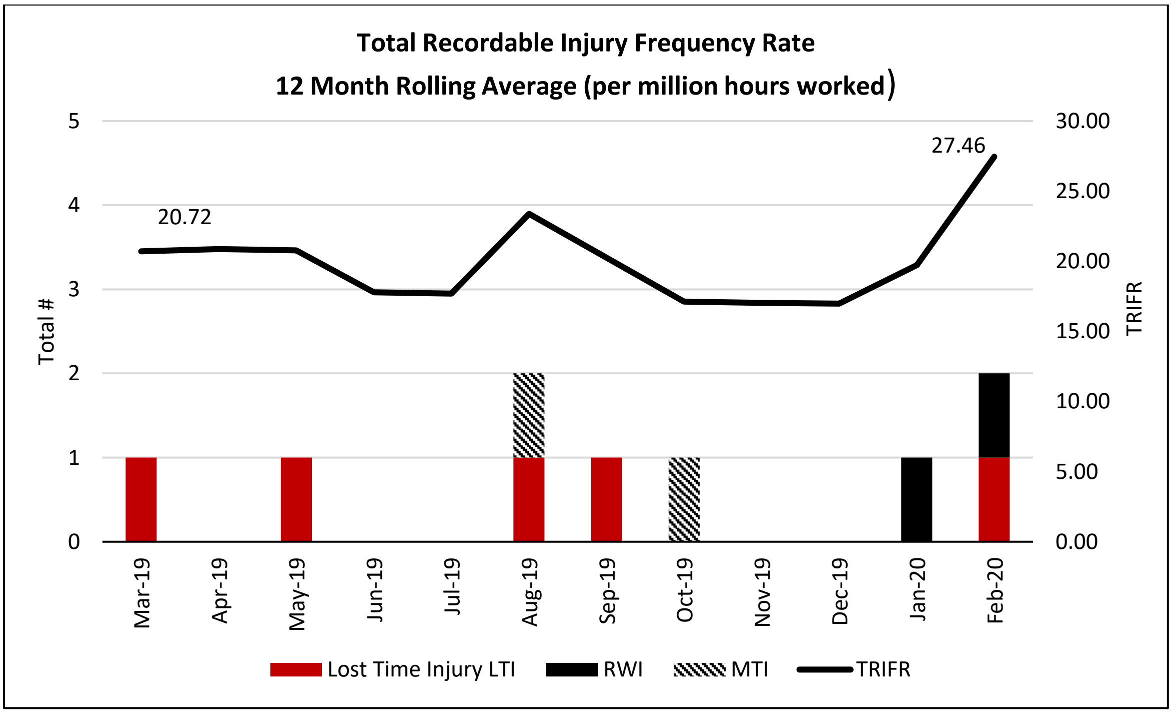

Figure 3 Total Recordable Injury Frequency Rate (TRIFR)

Our LTIFR and TRIFR reflects five lost time incidents over the past 12 months. These incidents were investigated fully, and improvements have been implemented with resulting changes and learnings notified out to the business. This has included refresher training on the requirements of reporting incidents, to ensure the correct level of support (i.e. physio) can be arranged and alternative duties implemented.

We continue with high levels of safety related training and engagement by continually considering what we can do differently. The company conducted a Stop for Safety day in November with a focus on mental health awareness and a workshop to identify safety and wellbeing opportunities across the business. The results fell into three broad categories:

- Training;
- Communications, team building and culture; and
- Planning, plant and equipment.

2.3. Public safety measures and targets

Our objective is to ensure that no member of the public is harmed by our network assets, and that hazards introduced by our network assets are controlled so as to not pose a risk to the public.

Leading indicators

Categories for leading public safety indicators include:

- Number of asset inspections and tests undertaken on:
  - High risk asset categories in the public domain – pillars, transformers, ring main units, poles, zone substations;
  - Safety critical assets – earthing, protection systems; and
  - Assets in special locations – those located around schools, public recreation spaces, commercial and shopping areas.
- Time to repair high risk defects on the network (percentage completed within required timeframes); and
- Number of external stakeholder engagement activities such as public safety notifications and school safety visits.

Lagging indicators

In addition to leading indicators, we record lagging indicators including:

- Number of incidents reported with or without harm; and
- Number of damaged property incidents (consumer premises and network property).

Actual performance for FY2018 to FY2020 are shown in the table below.

Details	FY 2018	FY 2019	FY 2020 YTD[2]
Property Damage to Network Assets	225	429	286
Reported Injuries from Network Assets	2	5	4

Table 1 Public safety lagging indicators

2.4. Reliability and network performance

Our objective is to operate the network to provide a level of performance in line with the price consumers are willing to pay. This includes:

- Minimising the number and duration of outages experienced by consumers;
- Restoring power as quickly and safely as possible following an unplanned outage and providing communication to keep consumers informed; and
- Providing consumers with sufficient notice ahead of planned outages required for maintenance.

As an exempt Electricity Distribution Business (EDB), our network performance indices have not been required to be calculated in accordance with the Commerce Commission default price-quality path (DPP) methodology, although we have taken that into account when assessing network performance. We note that the reference period 2004 – 2014 used for the Commerce Commission reliability calculation included a large period of relatively benign weather compared to recent weather trends, the network assets in some areas were 10 years newer, and the widespread use of live line techniques during that period means that the reference years are not necessarily representative of future network performance. We measure network performance by the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI).

Our total SAIDI and SAIFI performance in 2019 was unfavourable against target, however we did see a decrease in unplanned SAIDI. Our planned SAIDI has increased year on year pertaining to the large works programme to improve network reliability.

Our SAIDI target has increased from 200(2020) to 230(2021) and reducing to 220 in 2022. Our SAIFI target has increased from 2.80(2020) to 3.0(2021) and reducing to 2.90 in 2022. We base our performance targets on regular customer survey data identifying their preferences for the level of service against the costs of delivery. Furthermore, our new targets are reflective of recent network performance whereby increased ageing equipment failure rates are contributing to high unplanned outage numbers. To address these issues, we have accelerated our asset renewal programme, details of which can be found in section 3.2.

Historical performance and future targets are shown in the following graphs.

[2] FY2020 YTD is up to February 2020

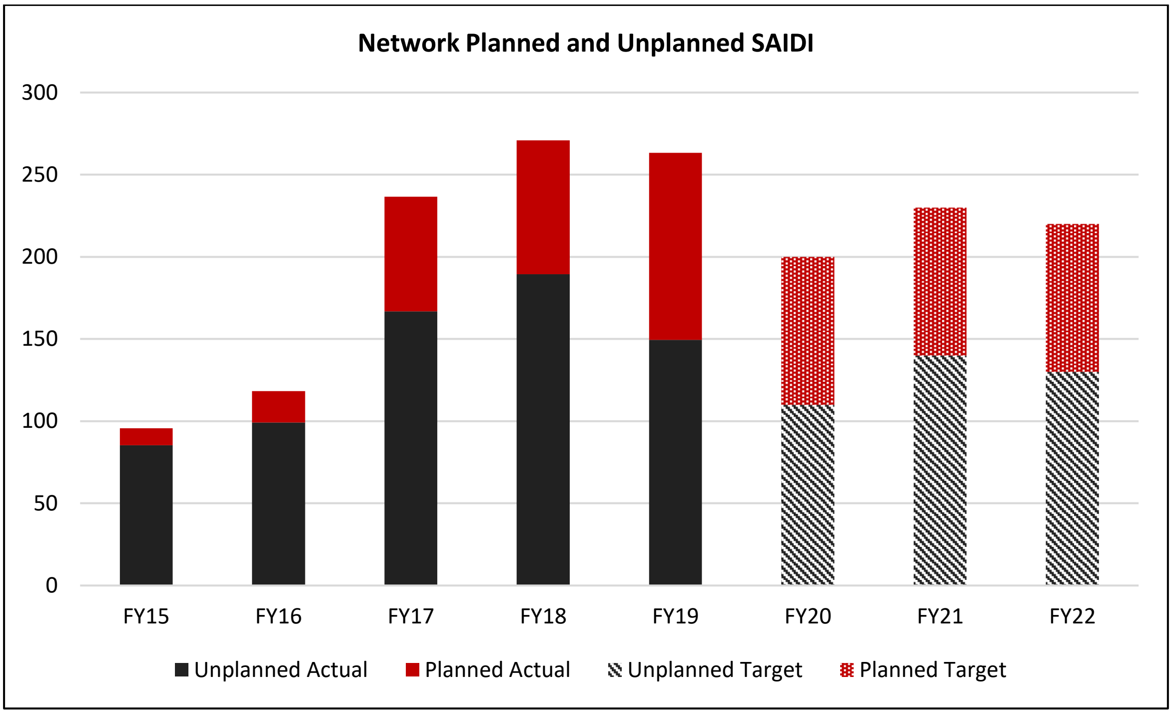

Figure 4 Network SAIDI utilising DPP normalisation

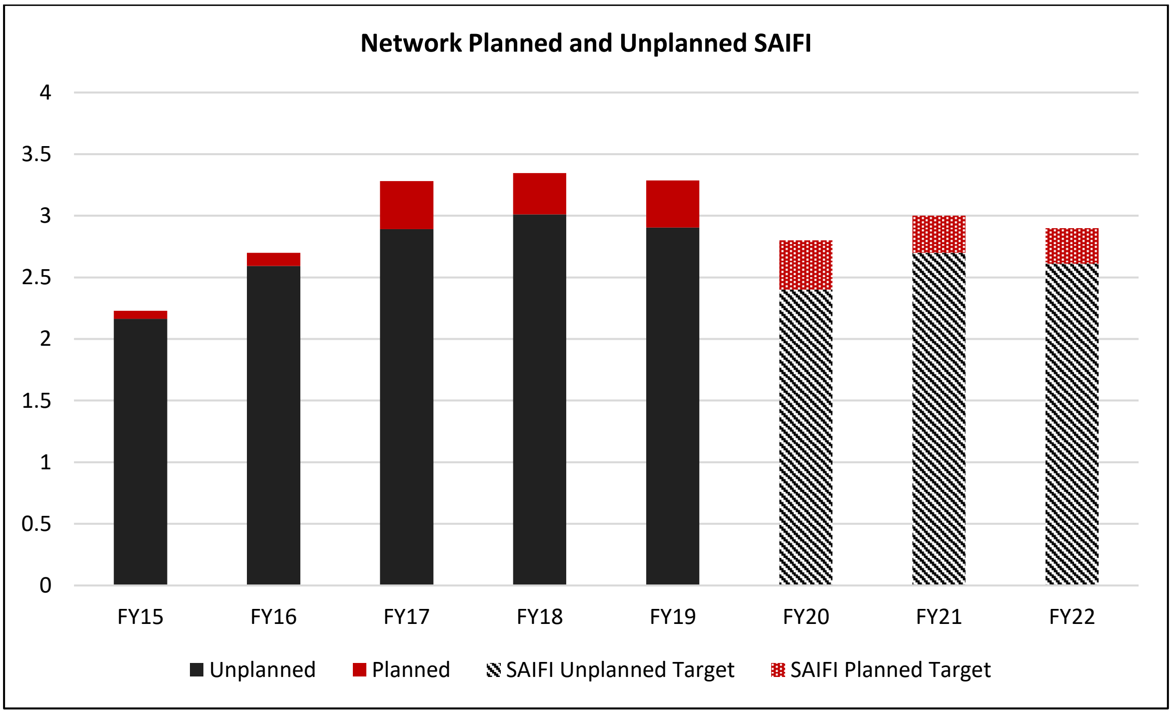

Figure 5 Network SAIFI utilising DPP normalisation

Faults per 100km	2017	2018	2019
Counties Power	18.51	23.32	117.0[3]
Industry Average	24.45	31.59	26.86

Table 2 Network faults per 100km performance

In our 2019 AMP, we noted that against historic performance, the indices had been negatively impacted by both the changes to live line working and also to the changes to manual circuit reclosing on 'no fault found' events. We have instituted a number of initiatives to achieve an improvement, primarily focussed on SAIDI performance, which included establishing feeder automation (remotely operable HV switches and fault current monitoring systems), additional focus on vegetation management and targeted accelerated replacement of ageing equipment/lines.

In 2019, we submitted a response regarding network performance to the Commerce Commission further detailing our trends and actions in the following areas:

- Unknown interruptions;
- Interruptions and duration;
- Vegetation management; and
- Defective equipment.

[3] The 2019 'faults per 100km' result is elevated (117.0) due to a single fault on a 33kV subtransmission underground circuit calculated against the total subtransmission cable circuit length of 1.1km. This single fault had a 'faults per 100km' rate of 90.91.

3. Asset Management Plan Update material changes

This section describes the material changes since our 2019 AMP. This includes:

- Material changes to our network development;
- Material changes to our asset lifecycle management (maintenance and renewal);
- Material changes to our asset management practices;
- Material changes in Schedule 11a Capital Expenditure; and
- Material changes in Schedule 11b Operational Expenditure.

3.1. Material changes to network development

The network development forecast includes system growth, quality of supply and reliability, safety and environment. The material changes to our network development plans have been driven from lower than expected increases in demand observed during 2019 compared to what had been forecast previously and the subsequent improvements we have made to our demand forecast.

The network is experiencing continued growth. Whilst the largest increase has been in residential properties, the growth in industrial and commercial properties also continues. As at September 2019, there were 43,381 ICPs connected to the Counties Power network with a maximum demand of approximately 128 MW and annual delivered energy of 584 GWh in the year ending 31 March 2019. Our peak demand was 129 MW during the 2019 winter peaks. A breakdown of the ICP type is shown in the table below:

	ICPs	Delivered GWh
Direct supply	9	69.5
Time-of-use	166	120.4
Commercial	7,006	116.8
Domestic	36,200	277.1
Total	**43,381**	**583.8**

Table 3 Delivered GWh in FY19

Domestic ICP growth is reflective of the focus on providing housing in targeted areas within the wider Auckland region. Subdivisions in the Pukekohe, Drury, Karaka, Glenbrook and Pokeno areas have had elevated uptake rates in the last year.

Industrial connections have continued to grow including the new Synlait Dairy Plant at Pokeno, however the actual demands generated by new industrial connections has been lower than predicted. This appears to reflect the start-up phase and growth is expected to continue.

Furthermore, industrial growth in the Drury South area has not eventuated within the anticipated timelines. A further factor is the rate of growth at Paerata Rise and the surrounding area (Pukekohe North). Depending on the actual rate and order of development, it will be possible to defer the Quarry Road (Drury South), Pukekohe North zone substations and the Drury GXP connection until growth dictates their establishment. Similar approaches will be applicable to the future Kingseat and Glenbrook area zone substations.

Our forecasts are based on current growth trends and information at hand. Taking these into consideration, we updated our assumptions for our demand forecasting. These included a lower rate of growth in line with actual recent growth rates, impact of temperature variations on demand and anticipated impact of EV's.

The present load forecast for the total network is shown below in Figure 6. This is shown alongside the corresponding forecast from the 2019 AMP.

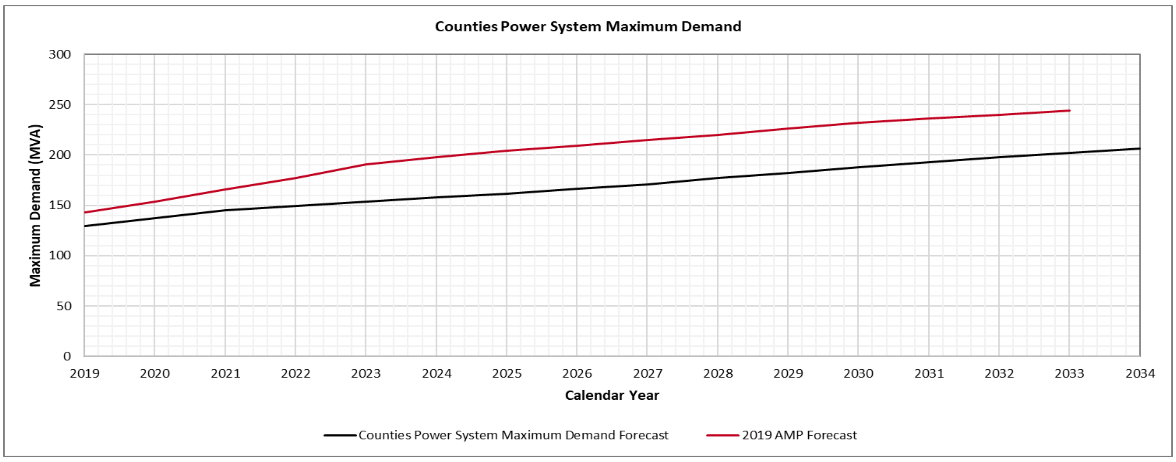

Figure 6 Maximum demand forecast

Figure 7 below shows the 10 year network development CAPEX forecast compared to the 2019 AMP. There are no significant new major Network Development projects expected within the planning period, however we have reprioritised our system growth projects which has resulted in network development capital expenditure deferment.

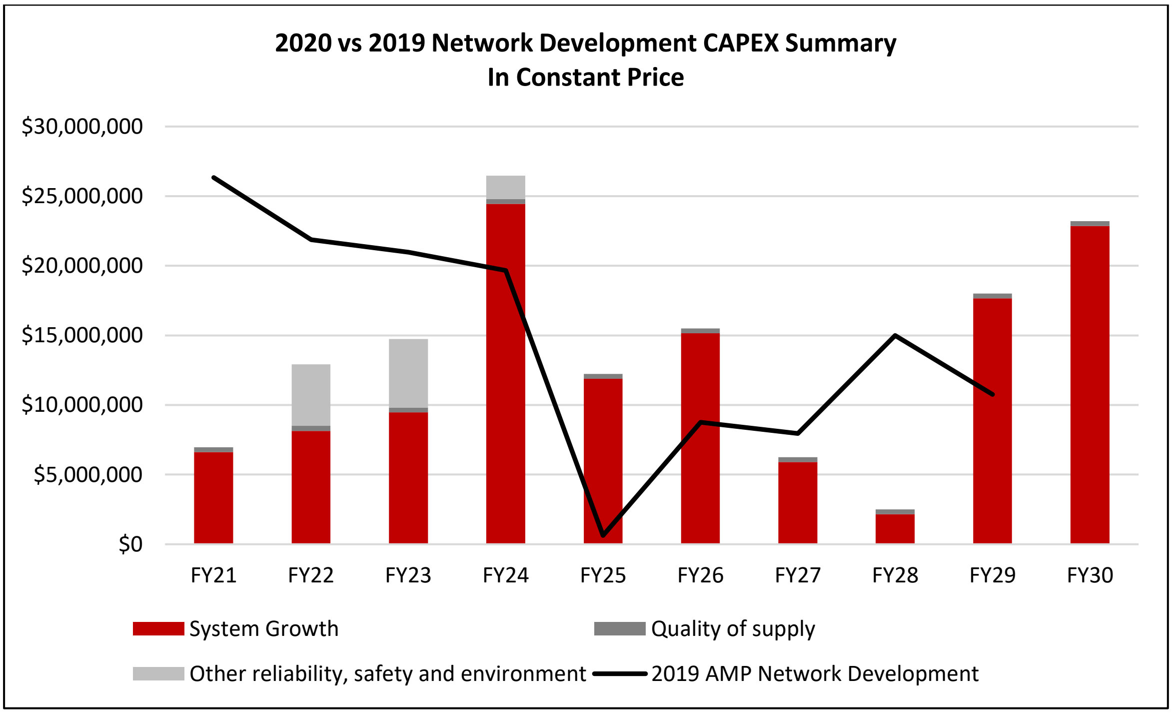

Figure 7 Network development CAPEX forecast

3.1.1. Material changes to network development substation programme

The main changes to network development substation programme are outlined in Table 4 below.

Substation	Project	AMP2019 Financial Year	AMP2019 Estimated Cost ($000's)	Updated Financial Year	Updated Estimated Cost ($000's)
Network development zone substation programme					
Quarry Road (previously Drury South)	110/22kV Substation	FY21	19,000	*Shown below*	*Shown below*
	110kV procurement	*Included above*	*Included above*	FY23	4,150
	110kV switching station	*Included above*	*Included above*	FY24	6,850
	22kV procurement	*Included above*	*Included above*	FY29	5,650
	Build 22kV substation	*Included above*	*Included above*	FY30	1,350
	Drury GXP connection and 22kV feeders	FY23	2,000	FY31	4,500
Pukekohe North	Land acquisition	FY20	2,300	FY21	2,350
	110kV line & route design	FY21	1,500	FY21-22	800
	110kV line construction	FY26	7,400	FY24	*No change*
	Substation construction and feeder connections	FY27-30	17,400	FY25-26	17,600
Kingseat	Land acquisition	FY20	2,000	FY21	1,950
	33kV Line design	FY22	1,000	FY22	500
	33kV line construction	FY23	2,100	FY26-27	*No change*
	Substation design	FY23	1,000	*No change*	*No change*
	Substation construction and feeder connections	FY23-24	10,100	FY26-27	*No change*
	Feeder upgrades	FY28	14,500	FY28-30	*No change*
Glenbrook Beach	Land acquisition	FY21	2,000	FY23	*No change*
	33kV Line design	FY22	1,500	FY28	500
	Substation construction	FY30	20,500	FY29-30	*No change*

Table 4 Network development substation programme – material changes

Quarry Road zone substation

In our 2019 AMP, Quarry Rd zone substation (previously referred to as Drury South zone substation) was to be established in FY21. This has been deferred whereby an 110 kV switching station will now be established in FY23/24 (to provide supply for the proposed Pukekohe North zone substation) and the 110/22 kV substation scheduled to be established in FY30 with the associated Drury GXP connection estimated to be undertaken FY31 onwards. Cost estimates have been updated based on learnings from recently completed substation projects.

We note that there is potential for significant residential and commercial development in the wider Drury South area and will continue monitoring this against the need for a substation to provide supply.

Pukekohe North zone substation

Based on the latest load forecasts for the area, the establishment of Pukekohe North zone substation has been brought forward to FY25/26 from FY27-30. Land acquisition had been scheduled for FY20 but will be completed in FY21 with the 110 kV line route design to follow. Cost estimates have been updated based on learnings from recently completed substation projects.

Kingseat and Glenbrook Beach zone substations

The establishment of the Kingseat zone substation has been deferred to FY26/27 from FY23/24 based on updated load forecasts. Land acquisition had been scheduled for FY20, but will be completed in FY21, with 33 kV subtransmission line design to follow in FY22. We have updated 33kV line design cost estimates based on learnings from recently completed 33kV subtransmission projects.

The establishment of the Glenbrook Beach zone substation has been brought forward to FY29/30 from FY30 based on updated load forecasts, while land acquisition has been deferred from FY21 to FY23 and 33 kV subtransmission line design has been deferred to FY28 from FY22.

We note that there is potential for acceleration or deceleration of the Kingseat and Glenbrook Beach residential developments and will continue to monitor the uptake rates and reprioritise the projects as more information becomes available. Kingseat and Glenbrook Beach zone substations will support each other and the establishment of either will contribute to deferment of the other.

3.1.2. Material changes to network development feeder programme

The material changes to the network development feeder programme is shown in Table 5 below.

Substation	Project	AMP2019 Financial Year	AMP2019 Estimated Cost ($000's)	Updated Financial Year	Updated Estimated Cost ($000's)
Feeder programme					
Opaheke	New feeder to offload Papakura South and Beach Road (previously Beach Road feeder split)	FY24	1,250	*No change*	2,000
	New Park Estate Feeder (previously Hingaia feeder split)	FY24	500	FY25	1,500
	New feeder to offload Red Hill (previously Red Hill feeder split)	FY24	1,800	FY24	1,000
	New feeder to offload Drury Feeder	*New*	*New*	FY24	1,000
Pukekohe	Cape Hill feeder split	FY24	750	FY22	3,000
	Pukekohe West feeder split	FY24	800	FY22-23	2,850
Mangatawhiri / Ramarama	Bombay feeder conversion	FY21	3,000	FY22	4,500
	Great South Road feeder conversion	FY23	3,000	FY22	1,500
Karaka	Blackbridge feeder conversion	FY27	5,000	*Removed*	*Removed*
Waiuku	Waiuku Town and Te Toro feeder underground	FY22	500	FY21	600
	Manukau Heads and Te Toro transformer tap position review	*New*	*New*	FY23	350

Substation	Project	AMP2019 Financial Year	AMP2019 Estimated Cost ($000's)	Updated Financial Year	Updated Estimated Cost ($000's)
	Te Toro and Manukau Heads feeder upgrades	FY22	1,040	FY23	*No change*
Maioro	Otaua feeder voltage regulator	FY22	350	FY26	*No change*

Table 5 Network development feeder programme – material changes

Opaheke Zone Substation feeders

Following the establishment of a new 22kV switchboard at the Opaheke Substation in FY23, new feeders will be created to offload existing feeders to align with our security criteria. In our 2019 AMP, feeder splits were identified for the Beach Road, Hingaia and Red Hill Feeders.

For the Beach Road feeder, the timelines remain unchanged however the cost estimate has increased due to the inclusion of additional undergrounding in urban areas to reduce the likelihood of unplanned outages. Furthermore, the scope has also been updated to undertake enabling works for the establishment of a new feeder following the Opaheke 22kV switchboard upgrade.

The Hingaia Feeder split identified in the 2019 AMP has now been replaced with the establishment of a new Park Estate Feeder in FY25. The cost estimate increase is driven by location changes of key equipment driven by proposed developments along Park Estate Road.

The Red Hill Feeder split has been replaced with the establishment of a new feeder, however the cost estimate has decreased due to major components of this project being undertaken as part of renewal programmes in FY21. Furthermore, a new feeder to offload the Drury Feeder has been introduced which will assist in supplying anticipated loads in the Drury area developments.

Pukekohe Zone Substation feeders

Feeder splits on the Cape Hill and Pukekohe West feeders were identified in the 2019 AMP to provide interim alignment with our security criteria pending the upgrade of the existing 22kV substation switchboard. The cost estimates for these projects have increased due a scope change to include undergrounding of existing overhead sections in urban areas to reduce likelihood of unplanned outages. Furthermore, new outgoing circuit routes are being introduced from the Pukekohe Zone Substation which will be converted into new feeders following the 22kV switchboard upgrade currently planned for FY31.

Mangatawhiri and Ramarama Zone Substation feeders

The timing for the 22kV conversion of the Bombay and Great South Road feeders have been updated to align with the new Barber Road 110/22kV substation. The cost estimate for Great South Road feeder has been updated to align with ageing infrastructure renewal programmes which will ultimately prepare the overhead network for the conversion. For Bombay feeder 22kV conversion project, a more detailed scoping exercise has been undertaken which has increased the overall cost estimate.

Karaka Zone Substation feeders

The Blackbridge Feeder 22kV conversion project has been deferred due to the proposed Pukekohe North zone substation and upgrades on the Opaheke zone substation feeders.

Waiuku Zone Substation feeders

A new project to undertake a review of transformer tap positions on the Manukau Heads and Te Toro feeders has been introduced, the results from which will influence the Manukau Heads and Te Toro feeder upgrade projects.

Maioro Zone Substation feeders

The establishment of the Otaua feeder voltage regulator has been deferred to FY26 from FY22 due to reduced load forecasts for the area.

$12.1m

DISCOUNT FOR CUSTOMERS

3.2. Material changes to lifecycle asset management (maintenance and renewal)

We have completed a network reliability study in 2019 and as a result of this review, there have been the following material changes:

- Accelerated conductor replacement programme particularly ageing 16mm^2 Copper and Swan (aluminium) conductor;
- Accelerated ring main unit (oil filled and air insulated) replacement; and
- Accelerate protection replacement.

The Barber Road zone substation (previously known as the Bombay Area zone substation) has been reclassified as a renewal project as it is replacing two end of life substations. This accounts for $21.5m between FY21 – FY25.

The expenditure and material changes are outlined in Figure 8 and Table below.

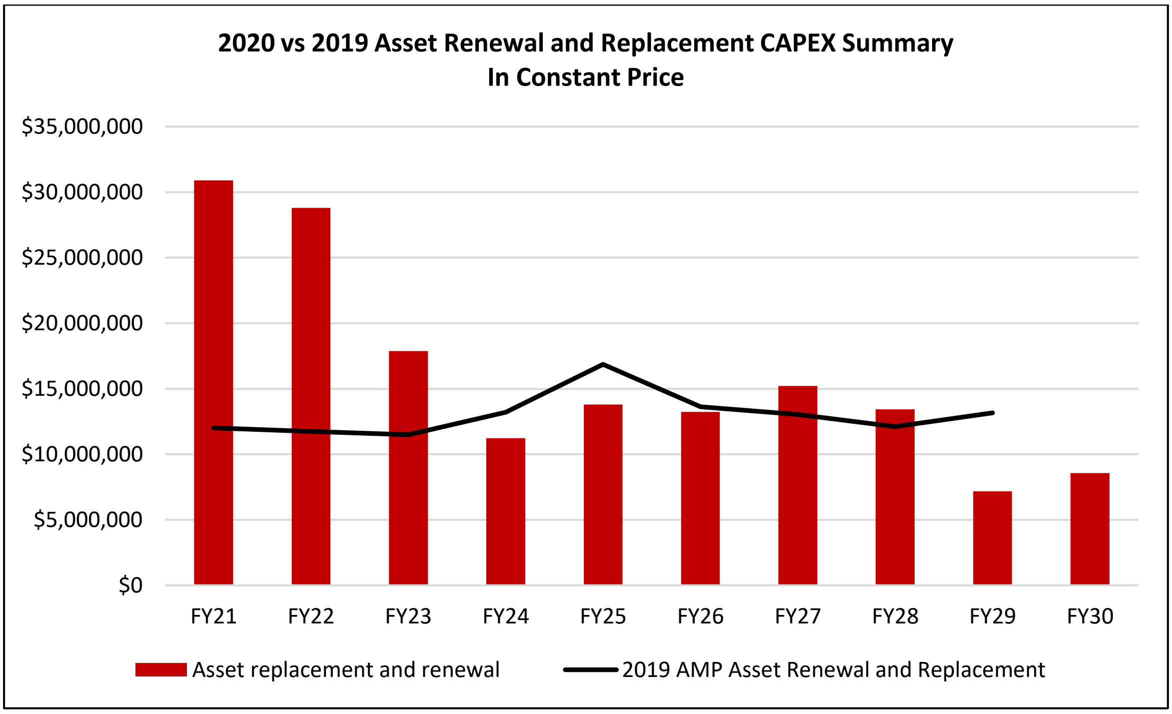

Figure 8 Asset Renewal and Replacement CAPEX forecast

Feeder	Programme	AMP2019 Financial Year	AMP2019 Estimated Cost ($000's)	Updated Financial Year	Updated Estimated Cost ($000's)
Railway feeder (Outside racecourse)	Conductor Replacement	FY21	180	*No Change*	280
Glen Murray	Conductor Replacement	FY21	180	*No Change*	260
Bombay feeder Razor back road	Conductor Replacement	FY24	190	FY21	600
Great South Road (Runciman Road)	Conductor Replacement & Feeder conversion	FY25	729	FY21	*No Change*
Patumahoe (Township)	Conductor Replacement	FY23	780	FY21	*No Change*
Pukekohe East (Tuhimata Road)	Conductor Replacement	FY21	550	FY24	*No Change*
Patumahoe (except township)	Conductor Replacement	FY24	415	FY23	*No Change*
Great South Road	Conductor Replacement & Feeder conversion	FY25	1,480	FY21	1,780
Blackbridge (Lewis Road)	Conductor Replacement	FY24	820	FY22	*No Change*
Dominion Road-Tuakau Feeder	Conductor Replacement	FY24	309	FY23	*No Change*
Red Hill feeder	Conductor Replacement	FY21	750	FY21	2,700
Pukekohe Hill (Anzac Road)	Conductor Replacement	FY21	300	FY21	490
Beach Road Stage 1	Kiosk replacement	FY22	1,175	FY21	1,500
Beach Road Stage 2	Kiosk replacement	FY23	1,310	FY21	1,350
Racecourse	Kiosk replacement	FY24	500	FY21	*No Change*
Drury Hills	Kiosk replacement	FY24	877	FY24	*No Change*
Tuakau/ Pukekawa	Protection	*New*	*New*	FY21	1,440
Karaka 33kV	Protection	*New*	*New*	FY22	360
Bombay/Pukekohe	Protection	*New*	*New*	FY23	190
Karaka 11kV switchboard replacement	Condition Based Replacement	FY29	1,200	FY31	2,500
Establishment of Barber Road Substation	Eastern Network Development	FY22 - 23	12,700	FY21 - 22	16,650
Decommissioning of existing 33kV assets	Eastern Network Development	FY24 - 26	3,000	FY23 - 25	4,200
SCADA communication network resilience improvement	Eastern Network Development	FY21	1,500	FY21 - 23	700

Table 6 Asset Renewal and Replacement Programme – Material Changes

Aged conductor replacement programme

A number of conductor replacement programmes have been accelerated over the next 3 years from our 2019 AMP due to continued deterioration of Copper and Swan conductor as a result of trends identified in recent reliability and performance studies. The cost estimates have been updated to account for improved design and construction standards.

Great South Road Copper replacement

These replacement works have been accelerated to align with the new Barber Road zone substation development works.

Papakura South and Beach Road kiosk replacement

To maximise the delivery resources and minimise long term interruption in the area, it is intended to combine all stages of the Papakura South and Beach Road kiosk replacement projects as a continuous replacement programme.

Red Hill feeder conductor replacement

Swan conductor on the Red Hill feeder had been identified for replacement in our 2019 AMP. The timing of this project remains unchanged, however the budget for this project has increased from $750k to $2,700k. This is due to the scope being upgraded following recent SAIDI performance on this feeder. The original scope was to reconductor copper and swan sections, however the scope has now been updated to include 3.7km of undergrounding.

Tuakau and Pukekawa protection relay replacement

The replacement of protection relays at Tuakau zone substation and Pukekawa switching station has been introduced for implementation in FY21 due to poor performance, with an unsatisfactory number of relays having failed and been replaced since the stations were commissioned in 2014.

Mangatawhiri and Ramarama zone substation replacement

Our 2019 AMP identified a new substation (Barber Road) to replace our zone substations at Mangatawhiri and Ramarama, scheduled to be established in FY22/23. This substation will now be established over FY21 and FY22. This has been brought forward in part due to the deferral of the Quarry Road zone substation and will allow us to better manage the risk of end of life 33kV assets. Cost estimates have been updated based on learnings from recently completed substation projects.

Karaka 11kV switchboard replacement

The Karaka 11kV switchboard replacement project due to the age of the existing switchboard has been deferred to FY31 from FY29. The estimated cost has also been adjusted based on the costs from our recent Waiuku 11kV switchboard replacement project.

3.3. Material changes to asset management practices

We continually seek opportunities to improve services to meet our stakeholder's requirements. The following sections describe the changes we are making for this year's AMP.

3.3.1. Changes in network development strategy

We updated our network development strategy as described in the sections below:

- **Adopting an upper and lower load forecast**

  We adopted temperature variations and its impact on peak loads particularly in winter. In doing so, we adjusted for peak load variation per degree of temperature variation and adopted a standard temperature of 9.0°C at the time of system peak. Furthermore, we incorporated the impact of EV's on load growth by utilising data publicly available in relation to the number of EV's registered in New Zealand and on our network. This data fed into the overall network demand forecast for the planning period and we anticipate to improve on this forecasting in the next planning cycle.

- **Aligning network build versus load growth**

  We undertook a study this year to gauge the timing between new residential and industrial network being built against new load coming on. This was particularly important to ensure investment is made in the right areas as required by the accelerated load growth we are experiencing. We have found that, on average, there is a delay of 2-3 years for residential, and 1-2 year for industrial loads to eventuate following the building of the network. This has been incorporated into our load forecasts, in particular all ongoing and known upcoming developments in our network.

3.3.2. Changes in asset replacement and renewal strategy

We updated our asset replacement and renewal strategy as described in the sections below:

- **Alignment of renewal and system growth projects**

  System growth projects are driven either by third party load requirements or capacity constraints. These don't necessarily align with replacement and renewal requirements for the network, with typically our ageing rural network requiring attention versus urban networks for growth projects.

  We have, in our forward works programme, included asset replacement and renewal projects within areas of system growth to recognise resource efficiencies. This includes accelerated replacement and renewal projects in areas where growth is occurring. These projects are included in addition to the ageing rural network projects.

- **A new 22kV design standard**

  We have placed a large emphasis on network performance, which ultimately impacts our consumers. In 2019, we undertook analysis on unplanned outages in an effort to identify the common failure modes and to develop initiatives to reduce overall unplanned outages.

One of our initiatives is the development of a new 22kV design standard. This will involve construction of designs that allow for increased clearances and added robustness with an aim to reduce failure rates. This will be adopted on all overhead line projects in 2020 including new builds and renewal work where practicable.

- **Accelerate and prioritised asset replacement and renewal**

  We have accelerated ageing asset replacement and renewal. This includes replacement of overhead conductor (Copper and aluminium), oil filled ground mounted switchgear, air insulated ground mounted switchgear, paper insulated cables and ageing poles (wood, concrete and iron rail) and crossarms. Areas are prioritised based on public safety risk, recent performance, population density, asset age and condition.

3.4. Material changes in Schedule 11a Capital Expenditure

Residential and industrial growth within the region is expected to continue, however the increases anticipated in 2019 have not eventuated. To reflect this trend and our updated demand forecast, we have reprioritised our system growth projects which has resulted in network development capital expenditure deferment. Furthermore, we have decreased our customer initiated work forecast by $3.6m for the planning period. However, to address network reliability and ageing asset failure, we have brought forward renewal and replacement expenditure. Our non-network capital expenditure has increased by $12.0m largely driven by our head office refurbishment, IT, innovation and customer service initiatives.

Figure 9 below shows our forecast 10 year capital expenditure compared to our 2019 AMP capital expenditure forecast.

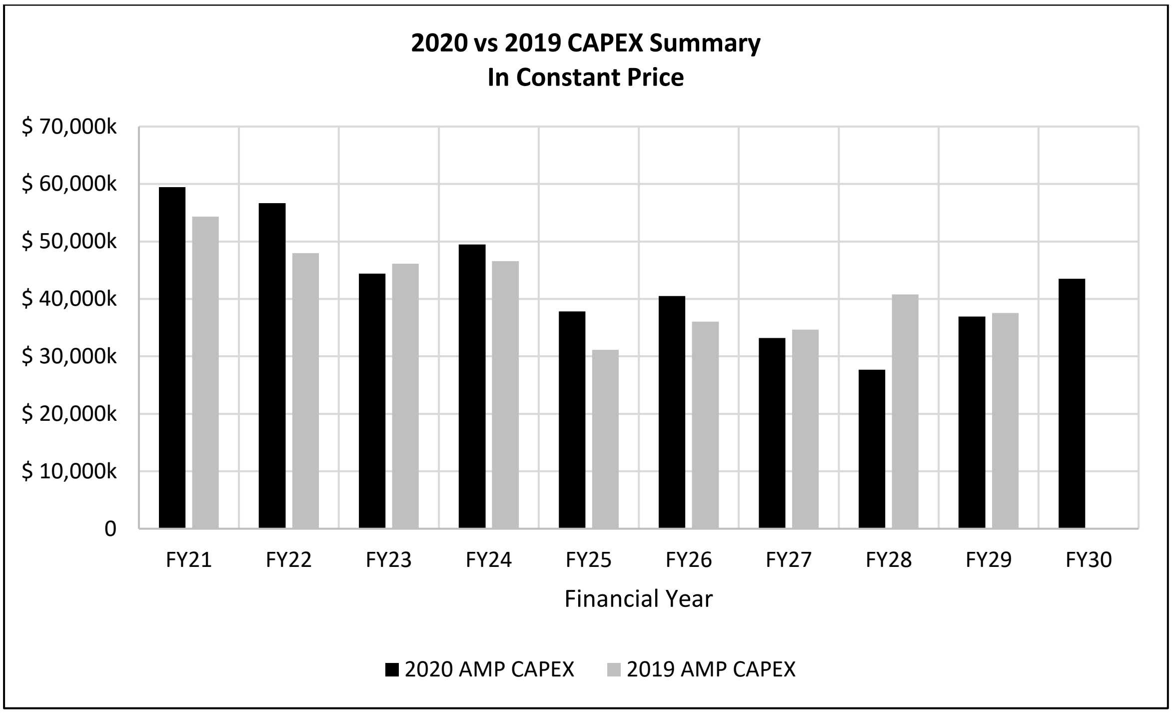

Figure 9 Capital expenditure forecast comparison

3.5. Material changes in Schedule 11b Operational Expenditure

Forecast OPEX across the planning period is $201m, which is an increase of $28m from the 2019 AMP forecast. Figure 10 below shows our forecast 10 year operational expenditure compared to our 2019 AMP operational expenditure forecast.

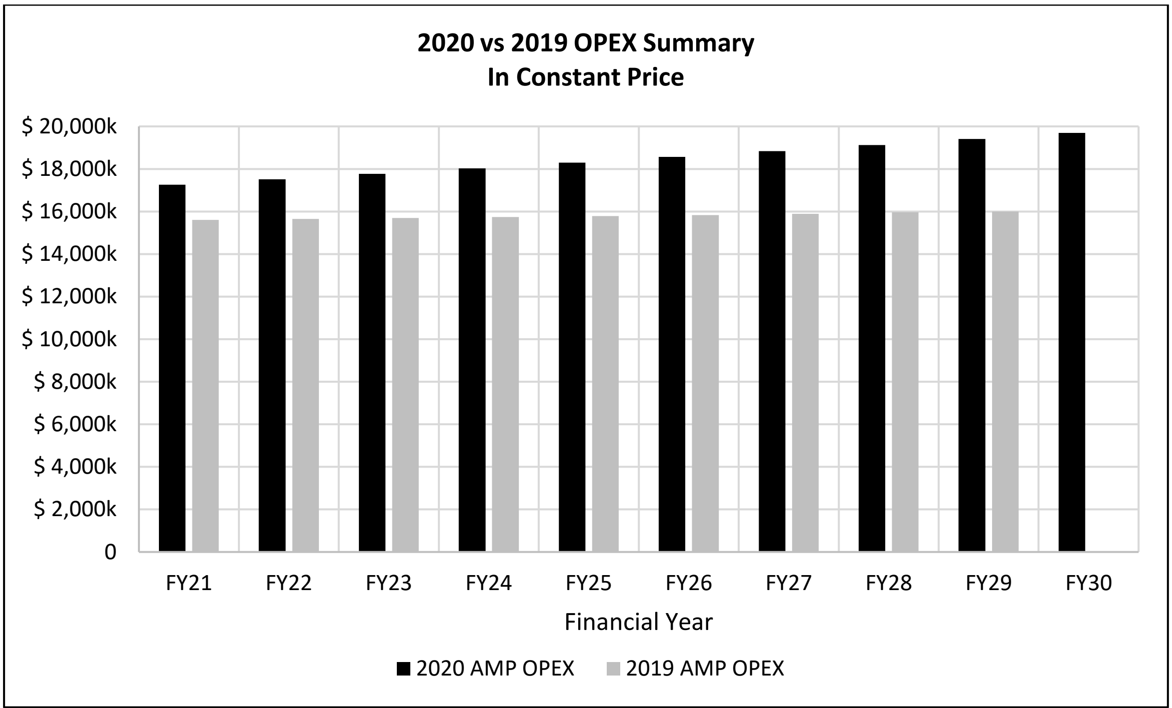

Figure 10 Operational expenditure forecast comparison

3.5.1. Network Operational expenditure

The network operational expenditure has increased from $58m forecast for the 2019 AMP planning period to $74m in this update.

The year on year increase in network operational expenditure is reflective of ongoing network growth and the increased maintenance costs associated with a growing asset base relating to:

- Overhead and Ground Mounted equipment – increase in assets year on year due to capital works and network growth;
- Construction of new zone substations increases asset numbers as related to power transformers, buildings, switchgear and protection inclusive;
- An increase in poles and crossarms in line with the new 22kV design standard. This includes the shortening of span lengths and re-routing from private property to road reserve where appropriate; and
- Increase in overhead network due to our ongoing HV service line ownership transfer initiative.

Furthermore, there are increases to the budgets for vegetation management and service interruption response, including additional staffing and resource for network performance improvements. Additionally, operational expenditure in corrective asset renewal reflects an increased focus on asset inspections and remedial works as the result of defect identification.

3.5.2. Non-Network Operational expenditure

The non-network operational expenditure has increased from $114m forecast for the 2019 AMP planning period to $127m in this update.

We have increased the level of expenditure in the IT area to address high growth on the network and upgrade systems to meet business requirements. Higher spend has been forecast going forward to support and maintain these systems. The company has also invested in improving the customer experience and will continue to prioritise this area in the future. Other business support including HR, Finance and Corporate has also increased to meet business requirements.

4. Schedules

COUNTIESPOWER

		Company Name	Counties Power Limited
		AMP Planning Period	1 April 2020 – 31 March 2030

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7														
8			for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
9	**11a(i): Expenditure on Assets Forecast**			**$000 (in nominal dollars)**										
10		Consumer connection		11,440	9,500	9,690	9,884	10,081	10,283	10,489	10,699	10,913	11,131	11,353
11		System growth		33,950	6,620	8,313	9,853	25,947	12,859	16,727	6,644	2,470	20,680	27,308
12		Asset replacement and renewal		14,500	30,909	29,382	18,593	11,916	14,938	14,596	17,117	15,417	8,416	10,229
13		Asset relocations		100	300	306	312	318	325	331	338	345	351	359
14		Reliability, safety and environment:												
15		Quality of supply		1,000	350	357	364	371	379	386	394	402	410	418
16		Legislative and regulatory		-	-		-	-	-	-	-		-	-
17		Other reliability, safety and environment		-	-	4,514	5,124	1,783	-	-	-	-	-	-
18		**Total reliability, safety and environment**		1,000	350	4,871	5,488	2,154	379	386	394	402	410	418
19		**Expenditure on network assets**		60,990	47,679	52,561	44,130	50,416	38,784	42,529	35,192	29,546	40,988	49,667
20		Expenditure on non-network assets		5,134	11,791	5,255	2,043	2,086	2,129	2,174	2,219	2,265	2,313	2,361
21		**Expenditure on assets**		66,124	59,471	57,816	46,173	52,502	40,913	44,703	37,411	31,811	43,301	52,028
22														
23	*plus*	Cost of financing		350	125	137	111	125	94	101	82	68	92	109
24	*less*	Value of capital contributions		9,152	8,500	8,721	8,895	9,073	9,255	9,440	9,629	9,821	10,018	10,218
25	*plus*	Value of vested assets												
26														
27		**Capital expenditure forecast**		57,322	51,096	49,232	37,389	43,554	31,753	35,364	27,864	22,058	33,375	41,920
28														
29		Assets commissioned		57,322	51,096	49,232	37,389	43,554	31,753	35,364	27,864	22,058	33,375	41,920
30				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31			for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
32				**$000 (in constant prices)**										
33		Consumer connection		11,440	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500
34		System growth		33,950	6,620	8,150	9,470	24,450	11,880	15,150	5,900	2,150	17,650	22,850
35		Asset replacement and renewal		14,500	30,909	28,805	17,871	11,229	13,801	13,220	15,200	13,422	7,183	8,559
36		Asset relocations		100	300	300	300	300	300	300	300	300	300	300
37		Reliability, safety and environment:												
38		Quality of supply		1,000	350	350	350	350	350	350	350	350	350	350
39		Legislative and regulatory		-	-	-	-		-	-	-	-	-	-
40		Other reliability, safety and environment		-	-	4,425	4,925	1,680	-	-	-	-	-	-
41		**Total reliability, safety and environment**		1,000	350	4,775	5,275	2,030	350	350	350	350	350	350
42		**Expenditure on network assets**		60,990	47,679	51,530	42,416	47,509	35,831	38,520	31,250	25,722	34,983	41,559
43		Expenditure on non-network assets		5,134	11,791	5,151	1,964	1,965	1,967	1,969	1,970	1,972	1,974	1,976
44		**Expenditure on assets**		66,124	59,471	56,682	44,380	49,474	37,798	40,489	33,220	27,694	36,957	43,535
45														
46	**Subcomponents of expenditure on assets (where known)**													
47		Energy efficiency and demand side management, reduction of energy losses												
48		Overhead to underground conversion		500	3,790	850	320	550	300	260	300	300	300	300
49		Research and development												

Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
50												
51–52	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	190	384	581	783	989	1,199	1,413	1,631	1,853
55	System growth	-	-	163	383	1,497	979	1,577	744	320	3,030	4,458
56	Asset replacement and renewal	-	-	576	722	687	1,138	1,376	1,918	1,996	1,233	1,670
57	Asset relocations	-	-	6	12	18	25	31	38	45	51	59
58	Reliability, safety and environment:											
59	Quality of supply	-	-	7	14	21	29	36	44	52	60	68
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	89	199	103	-	-	-	-	-	-
62	**Total reliability, safety and environment**	-	-	96	213	124	29	36	44	52	60	68
63	**Expenditure on network assets**	-	-	1,031	1,714	2,908	2,954	4,009	3,943	3,824	6,005	8,108
64	Expenditure on non-network assets	-	-	103	79	120	162	205	249	293	339	385
65	**Expenditure on assets**	-	-	1,134	1,793	3,028	3,116	4,214	4,191	4,118	6,344	8,493
66												

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
67		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
68	**11a(ii): Consumer Connection**							
69		*Consumer types defined by EDB**	**$000 (in constant prices)**					
70		Urban residential	5,720	4,750	4,750	4,750	4,750	4,750
71		Urban commercial	2,288	1,900	1,900	1,900	1,900	1,900
72		Rural residential	1,945	1,615	1,615	1,615	1,615	1,615
73		Rural commercial	1,487	1,235	1,235	1,235	1,235	1,235
74								
75		**include additional rows if needed*						
76		**Consumer connection expenditure**	11,440	9,500	9,500	9,500	9,500	9,500
77	*less*	Capital contributions funding consumer connection	9,152	8,500	8,550	8,550	8,550	8,550
78		**Consumer connection less capital contributions**	2,288	1,000	950	950	950	950
79	**11a(iii): System Growth**							
80		Subtransmission	320	2,750	1,300	-	11,400	-
81		Zone substations	26,880	2,770	-	7,150	2,850	7,500
82		Distribution and LV lines	1,300	-	6,400	1,840	6,000	280
83		Distribution and LV cables	5,250	600	-	-	4,200	4,100
84		Distribution substations and transformers	200	400	450	480	-	-
85		Distribution switchgear	-	-	-	-	-	-
86		Other network assets	-	100	-	-	-	-
87		**System growth expenditure**	33,950	6,620	8,150	9,470	24,450	11,880
88	*less*	Capital contributions funding system growth	-	-	-	-	-	-
89		**System growth less capital contributions**	33,950	6,620	8,150	9,470	24,450	11,880
90								

Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

11a(iv): Asset Replacement and Renewal

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
	$000 (in constant prices)					
Subtransmission	50	700	50	250	50	3,050
Zone substations	1,540	6,150	11,500	5,850	350	400
Distribution and LV lines	5,900	12,358	9,845	9,081	7,921	8,091
Distribution and LV cables	2,550	4,136	4,700	760	1,060	520
Distribution substations and transformers	910	400	400	400	400	400
Distribution switchgear	3,550	5,250	480	480	1,328	960
Other network assets	-	1,915	1,830	1,050	120	380
Asset replacement and renewal expenditure	14,500	30,909	28,805	17,871	11,229	13,801
less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
Asset replacement and renewal less capital contributions	14,500	30,909	28,805	17,871	11,229	13,801

11a(v):Asset Relocations

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
*Project or programme**	**$000 (in constant prices)**					
Others	100	300	300	300	300	300
**include additional rows if needed*						
All other project or programmes - asset relocations						
Asset relocations expenditure	100	300	300	300	300	300
less Capital contributions funding asset relocations						
Asset relocations less capital contributions	100	300	300	300	300	300

11a(vi):Quality of Supply

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
*Project or programme**	**$000 (in constant prices)**					
Voltage quality resolution	1,000	350	350	350	350	350
**include additional rows if needed*						
All other projects or programmes - quality of supply						
Quality of supply expenditure	1,000	350	350	350	350	350
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	1,000	350	350	350	350	350

COUNTIES POWER

Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
135	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	**$000 (in constant prices)**					
139							
140							
141							
142							
143							
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
150	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153	Feeder splits and reliability improvement projects	-	-	4,425	4,925	1,680	-
154							
155							
156							
157							
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	-	-	4,425	4,925	1,680	-
161	*less* Capital contributions funding other reliability, safety and environment						
162	**Other reliability, safety and environment less capital contributions**	-	-	4,425	4,925	1,680	-
163							

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
164							
165	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**

Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref

166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	IT	2,209	3,111	1,863	1,370	1,370	1,370
170	Vehicles	-	100	100	100	100	100
171	Plant and Equipment	-	50	51	53	55	56
172	Strategy and business development	-	700	490	-	-	-
173							
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure						
176	**Routine expenditure**	2,209	3,961	2,504	1,523	1,524	1,526
177	**Atypical expenditure**						
178	*Project or programme**						
179	Office Upgrade	2,925	6,300	2,206	-	-	-
180	Buildings - other	-	1,530	441	441	441	441
181							
182							
183							
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	2,925	7,830	2,647	441	441	441
187							
188	**Expenditure on non-network assets**	5,134	11,791	5,151	1,964	1,965	1,967

COUNTIES POWER

Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,800	2,100	2,184	2,271	2,362	2,457	2,555	2,657	2,763	2,874	2,989
11	Vegetation management	1,350	1,500	1,560	1,622	1,687	1,755	1,825	1,898	1,974	2,053	2,135
12	Routine and corrective maintenance and inspection	1,250	1,550	1,612	1,676	1,744	1,813	1,886	1,961	2,040	2,121	2,206
13	Asset replacement and renewal	700	1,130	1,175	1,222	1,271	1,322	1,375	1,430	1,487	1,546	1,608
14	**Network Opex**	5,100	6,280	6,531	6,792	7,064	7,347	7,641	7,946	8,264	8,595	8,938
15	System operations and network support	3,815	3,104	3,228	3,357	3,491	3,631	3,776	3,927	4,084	4,247	4,417
16	Business support	7,698	7,877	8,104	8,338	8,579	8,828	9,083	9,347	9,618	9,897	10,185
17	**Non-network opex**	11,514	10,980	11,332	11,695	12,070	12,458	12,859	13,274	13,702	14,145	14,602
18	**Operational expenditure**	16,614	17,260	17,863	18,487	19,135	19,805	20,500	21,220	21,966	22,739	23,541
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,800	2,100	2,141	2,183	2,226	2,270	2,314	2,359	2,406	2,453	2,501
23	Vegetation management	1,350	1,500	1,529	1,559	1,590	1,621	1,653	1,685	1,718	1,752	1,786
24	Routine and corrective maintenance and inspection	1,250	1,550	1,580	1,611	1,643	1,675	1,708	1,742	1,776	1,810	1,846
25	Asset replacement and renewal	700	1,130	1,152	1,175	1,198	1,221	1,245	1,270	1,295	1,320	1,346
26	**Network Opex**	5,100	6,280	6,403	6,529	6,657	6,787	6,920	7,056	7,194	7,335	7,479
27	System operations and network support	3,815	3,104	3,164	3,226	3,290	3,354	3,420	3,487	3,555	3,625	3,696
28	Business support	7,698	7,877	7,945	8,014	8,084	8,155	8,227	8,299	8,373	8,447	8,522
29	**Non-network opex**	11,514	10,980	11,110	11,241	11,374	11,510	11,647	11,787	11,928	12,072	12,219
30	**Operational expenditure**	16,614	17,260	17,513	17,770	18,031	18,297	18,567	18,843	19,123	19,408	19,698
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	404	491	505	520	536	551	568	584	601	619	637
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	43	88	136	187	241	298	358	421	488
43	Vegetation management	-	-	31	63	97	134	172	213	256	301	349
44	Routine and corrective maintenance and inspection	-	-	32	65	101	138	178	220	264	311	360
45	Asset replacement and renewal	-	-	23	47	73	101	130	160	192	227	263
46	**Network Opex**	-	-	128	264	407	559	720	890	1,070	1,259	1,459
47	System operations and network support	-	-	63	130	201	276	356	440	529	622	721
48	Business support	-	-	159	324	495	672	856	1,047	1,245	1,450	1,663
49	**Non-network opex**	-	-	222	454	696	949	1,212	1,487	1,774	2,072	2,384
50	**Operational expenditure**	-	-	350	718	1,104	1,508	1,932	2,377	2,843	3,332	3,843

Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	0.23%	2.99%	19.23%	32.84%	44.71%		3	3.83%
11	All	Overhead Line	Wood poles	No.	8.93%	4.58%	21.37%	8.93%	56.19%		3	8.11%
12	All	Overhead Line	Other pole types	No.	-	-		100.00%	-		3	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	4.68%	23.44%	41.91%	9.52%	20.45%		3	34.60%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	27.70%	72.30%		3	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	21.68%	-	78.32%		3	
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-		N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-		N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-		N/A	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-		N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-		N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-		N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-		N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-		N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	66.67%	16.67%	16.67%	-	-		3	33.33%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	66.67%	33.33%		3	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-		N/A	
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	33.33%	8.34%	58.33%	-		3	
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	20.69%	31.03%	48.28%		3	48.28%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-		N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-		N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	100.00%		3	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	17.72%	25.32%	15.19%	20.25%	21.52%		3	13.92%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	
35												

COUNTIES POWER

Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
36					**Asset condition at start of planning period (percentage of units by grade)**							
37	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	26.67%	33.33%	26.67%	13.33%		3	26.67%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.41%	7.94%	30.38%	38.92%	20.35%		3	6.84%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-		N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-		N/A	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	1.38%	0.78%	20.97%	76.87%		3	0.46%
44	HV	Distribution Cable	Distribution UG PILC	km	-	14.72%	29.31%	49.48%	6.49%		3	
45	HV	Distribution Cable	Distribution Submarine Cable	km					100.00%		4	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	21.62%	40.54%	37.84%		3	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-		N/A	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	10.15%	10.53%	18.53%	36.79%	24.00%		3	26.85%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	5.08%	5.08%	13.28%	31.25%	45.31%		3	5.08%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	6.17%	34.98%	39.56%	19.29%		3	0.79%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	1.23%	33.63%	40.22%	24.92%		3	1.12%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	33.33%	66.67%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	41.67%	58.33%	-	-	-		4	100.00%
55	LV	LV Line	LV OH Conductor	km	-	0.20%	0.73%	91.95%	7.12%		3	0.69%
56	LV	LV Cable	LV UG Cable	km	0.74%	1.12%	0.86%	41.32%	55.96%		3	0.74%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	3.55%	5.70%	90.75%		3	-
58	LV	Connections	OH/UG consumer service connections	No.	-	0.20%	27.02%	39.70%	33.08%		3	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	0.70%	11.27%	6.34%	27.46%	54.23%		3	40.85%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	12.07%	4.48%	4.14%	34.48%	44.83%		3	16.55%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	79.31%	20.69%		3	20.69%
62	All	Load Control	Centralised plant	Lot	-	-	40.00%	40.00%	20.00%		3	20.00%
63	All	Load Control	Relays	No.	4.59%	30.03%	0.47%	63.78%	1.13%		3	40.85%
64	All	Civils	Cable Tunnels	km	-	-	-	-	-		N/A	-

Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Pukekohe	39	60	n-1	8	65%	60	75%	No constraint within +5 years	
10	Opaheke	27	40	n-1	7	68%	40	93%	No constraint within +5 years	
11	Tuakau	21	40	n-1	5	52%	40	85%	No constraint within +5 years	
12	Ramarama	6	5	n-1	5	127%	40	36%	No constraint within +5 years	Ramarama Substation will be decommissioned and replaced by Bombay area substation in 2021/22.
13	Mangatawhiri	7	-	n	5	-	-	-	No constraint within +5 years	Mangatawhiri Substation will be decommissioned and replaced by Bombay area substation in 2021/22.
14	Waiuku	16	15	n-1	5	106%	20	91%	No constraint within +5 years	Existing constraint lifted following replacement of 11 kV switchboard.
15	Karaka	10	20	n-1	2	52%	20	69%	No constraint within +5 years	
16	Maioro	9	9	n	3	-	-	-	No constraint within +5 years	Maioro Substation firm capacity is subject to commercial agreement with the major customer on site for new investment in the 5-year period.
17						-				
18						-				
19						-				
20						-				
21						-				
22						-				
23						-				
24						-				
25						-				
26						-				
27						-				
28						-				

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name: **Counties Power Limited**

AMP Planning Period: **1 April 2020 – 31 March 2030**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref							
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
11	*Consumer types defined by EDB**						
12	Standard domestic	431	408	416	424	433	441
13	Low user domestic	354	335	341	348	355	362
14	Mass market business	138	131	133	136	139	142
15	Time of use business	3	3	3	3	3	3
	Distributed Streetlights	-	-	-	-	-	-
	Direct Charge	1	1	1	1	1	1
16							
17	**Connections total**	927	878	894	912	931	949
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	120	120	120	120	120	120
21	Capacity of distributed generation installed in year (MVA)	0.5	0.5	0.5	0.5	0.5	0.5
22	**12c(ii) System Demand**						
23		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)** — for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
25	GXP demand	129	137	145	150	154	158
26	*plus* Distributed generation output at HV and above	6	9	9	9	9	9
27	**Maximum coincident system demand**	136	146	154	159	163	167
28	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**	136	146	154	159	163	167
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	580	593	605	618	632	645
32	*less* Electricity exports to GXPs	-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation	44	48	48	48	48	48
34	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**	624	641	653	666	680	693
36	*less* Total energy delivered to ICPs	595	611	623	636	648	661
37	**Losses**	29	30	30	30	32	32
38							
39	**Load factor**	53%	50%	48%	48%	48%	47%
40	**Loss ratio**	4.7%	4.7%	4.6%	4.5%	4.7%	4.6%

Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	90.0	90.0	90.0	90.0	90.0	90.0
12	Class C (unplanned interruptions on the network)	110.0	140.0	130.0	125.0	125.0	125.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.40	0.30	0.29	0.29	0.29	0.29
15	Class C (unplanned interruptions on the network)	2.40	2.70	2.61	2.51	2.51	2.51

Schedule 14a Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

   This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8. *Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)*

2. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
The difference between nominal and constant prices reflects inflation of 2% per annum.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

3. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
The difference between nominal and constant prices reflects inflation of 2% per annum.

5. Director's Certificate

Schedule 17 Certificate for Year-beginning Disclosures

Clause 2.9.1

We, Douglas John Troon and Vernon John Dark, being directors of Counties Power Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a. The following attached information of Counties Power Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.5, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b. The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c. The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Counties Power Limited's corporate vision and strategy and are documented in retained records.

Douglas John Troon (Director)

Vern John Dark (Director)

Certified this 3rd day of April 2020